COMMITTEE WORKSHOP

BEFORE THE

CALIFORNIA ENERGY RESOURCES CONSERVATION

AND DEVELOPMENT COMMISSION

In the Matter of:	)	
	)	Docket No.
Preparation of the 2007 Integrated Energy Policy Report	)	06-IEP-1M
	)	
Scenario Analyses of California's Electricity System	)	
	)	

CALIFORNIA ENERGY COMMISSION

HEARING ROOM A

1516 NINTH STREET

SACRAMENTO, CALIFORNIA

MONDAY, JULY 9, 2007

9:02 A.M.

Reported by:
Peter Petty
Contract No. 150-07-002

COMMISSIONERS PRESENT

Jackalyne Pfannenstiel, Presiding Member

John L. Geesman, Associate Member

Jeffrey D Byron, Electricity Committee Presiding Member

ADVISORS PRESENT

Suzanne Korosec

Kevin Kennedy

STAFF and CONSULTANTS PRESENT

Lorraine White

Michael Jaske

ALSO PRESENT

Steve St. Marie, Advisor to Commissioner John Bohn
California Public Utilities Commission

Osman Sezgen
Pacific Gas and Electric Company

Jacqueline Jones
Southern California Edison Company

Rich Ferguson
Center for Energy Efficiency and Renewable Technologies

Eric Wanless
Natural Resources Defense Council

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Southern California Edison Company

Robin Smutny-Jones
California Independent System Operator

I N D E X

P R O C E E D I N G S

9:02 a.m.

PRESIDING MEMBER PFANNENSTIEL: This is an Energy Commission workshop in the Integrated Energy Policy Report Committee proceeding. And we are today here to discuss scenario analyses. This is the second of two workshops on scenario analysis of the electric system.

I'm Commissioner Pfannenstiel; I am the Presiding Commissioner on the IEPR Committee. To my right is Commissioner John Geesman, who is the Associate Commissioner on that Committee. To my left is Commissioner Jeff Byron who is the Presiding Commissioner on the Electricity Committee.

To his left is Kevin Kennedy, his Advisor. To Commissioner Geesman's right is his Advisor, Suzanne Korosec. And to Suzanne's right is Steve St. Marie who is joining us from the Public Utilities Commission. He's the Advisor to Commissioner John Bohn, who is an Associate with us on this Committee.

I have no introductory remarks. Do any of the other Commissioners? Well, then why don't I turn it to Lorraine White.

MS. WHITE: Thank you, Commissioner. My name is Lorraine White; I'm the Program Manager for the Integrated Energy Policy Report proceeding. And I welcome everyone. Thank you for joining us today for the workshop the second in a series of three, on the scenario analysis that we're doing for the 2007 Integrated Energy Policy Report proceeding.

Just a few housekeeping items to mention for those of you here joining us today. Most of you know this information, so I'll make it quick. But restrooms are out the double-doors and to the left. Snack bar for any refreshments is on the second floor.

In the event of an emergency we ask that you follow us calmly outside the building and join us across the street, kitty-corner, at the park until such time as we are allowed back in the building to continue our work.

For those of you joining us today, we have three ways to help facilitate participation. Of course, inviting you to join us personally and provide comments throughout the day.

But then also we have provided a call-in number for those wishing to ask questions or make

comments. That number is 800-857-6618. There is a passcode required. It is IEPR and I'm the call leader, Lorraine White.

In addition, for those of you who would like to follow along on our website, we are also providing a webcast of today's proceeding, so that folks can see the slides and hear the audio presentation.

And I encourage those that have joined us today to take full advantage of the workshop and provide us what input you feel is necessary to refine our work and improve the analysis.

As part of today's agenda, as I mentioned, this is the second in three workshops related to our scenario analysis. The first was held on June 18th in which Dr. Jaske provided a full description of the work that was being done, and some initial information on the results.

Today we're going to go into much more detail about the work, itself, the implications of the results, and remaining work. We'll cover the information on the remaining work in the beginning.

It's related to our engine power plant retirement and repowering assessment, which is

very much a part of this scenario evaluation.

We'll also be discussing the status of the lower UEG usage impacts on the natural gas market prices.

And also on the status of the water usage information as part of the environmental assessment of the scenario analysis.

Dr. Jaske will also go over the principal limitations of the study and the implication of the results. And how to examine those results within a particular framework.

We invite folks to provide us input at that point, constructive critique of the work and perhaps comments on the implications of this type of analysis for future work.

We'll also ask folks to provide us comment on the usefulness of the current policy discussions. In particular, I draw your attention to the list of questions that we've provided between the June 18th and today's workshop.

We won't necessary seek to answer all those questions today. We ask you to provide us your initial comments, realizing those questions have just been posed over the last couple of weeks to those who have been assisting us in the

development of this work.

But in particular, as we move towards our August 16th date, we definitely want to try and get as complete answers from various stakeholders possible to that part of the analysis.

We'll also be covering our next steps related to this work.

Most of you have seen this slide, so I won't belabor it. I just wanted to provide the context of this work. It's a new type of analysis that we're adding to our assessment and forecast related specifically to electricity and natural gas assessments.

This will be incorporated into the Committee's document that is currently under development and will be published towards the latter part of August. We're on the trajectory for adopting the Integrated Energy Policy Report by the October 24th business meeting, so that we can transmit it to the Governor by November 1st.

Related to this work we're asking parties to provide us comments by July 20th. As I mentioned, we'll have actually the fourth workshop -- the very first workshop was related to the

initial structure of the analysis -- and actually the fourth workshop is going to be on August 16th.

And then we'll hope to complete staff's analysis by late August of this year.

This is contact information for myself and Dr. Jaske. It's also information on where you can access all of the materials related not only to the scenario analysis, but to all of the Integrated Energy Policy Report proceeding documents and information. That is all accessible on our Commission's website.

If there are any questions I'd be happy to answer them. Otherwise, Commissioners, if I may pass it now on to Mike.

DR. JASKE: Good morning. For the record, my name is Mike Jaske with the staff, administratively in the Executive Office, and associated with the new energy supply analysis division.

One thing I want to emphasize is that my presentation will be relatively brief, at least by comparison to last month, where I droned on for hours, attempting to sort of give you an overview of the scenario definitions, themselves, the methods and the results.

The purpose of today's workshop, as the notice lays out, and did so back in May sometime whenever that was issued, is really to get more input from the stakeholders. I did decide in between the two workshops that because of the great volume of information that was presented in the form of the main report, the appendices and the associated spreadsheets that are available through the website, that some way of trying to deal with the results, and try to contrast and compare them across the scenarios might be useful as a starting point.

So that's the subject of the addendum report which really did almost nothing new; merely attempted to present the results in a way to make them be more digestible.

Here, again, is the team that has worked on this. Some of them are present here in the audience today; and to the extent that there are questions, I may draw upon them.

What we're trying to do, as has been explained before, is get a better understanding of those actions that lead toward large GHG reductions for the electricity sector. Trying to understand what the consequences of those actions

are; and begin the process of sort of tradeoff comparisons. And certainly cost information is one of the ways in which that tradeoff is being accomplished.

More for the record than anything else, we have produced a main report; we have produced appendices; we have produced Excel spreadsheets that provide way more detail than the written documents, themselves. And then there is this brief addendum report posted last week. As Lorraine indicated, there are still some pieces of information that are forthcoming.

The first is our analysis of the implications of retirement of aging power plants, particularly focusing on southern California. And essentially what we are doing is rerunning some of the scenarios to identify the way in which those power plants which are retired can be replaced in the context of the particular scenario that was already being analyzed.

So in a conventional replacement case, we're replacing them with conventional resources. In a high-efficiency case we're trying to replace them with as little new generation as possible, trying to ascertain the value of energy efficiency

for the local capacity requirements that those plants are largely serving right now. And similarly in the high renewables case, to what extent can renewables play that replacement role, perhaps with some modifications to the transmission system.

We hope to bring that forward in the next couple weeks. And, as Lorraine said, the plan is that that material will be discussed at the August 16th workshop.

Similarly we have had in process a piece of work that is taking the reduction in electric generation consumption from the various scenarios, and looking at what the natural gas price implications of that reduced use can be. That work is being done right now. And we also anticipate it will be documented by the end of this month and discussed at the August 16th workshop.

Okay, just to quickly remind you of the nine basic scenarios that were examined in this project. They stem from, at the top, sort of the current conditions extended out into the future. A sort of weak reliance upon efficiency renewables, other preferred resources and heavier

emphasis on conventional resources. All the way up through case 5B, which has high levels of energy efficiency and high levels of renewables through the whole west, and various or specific ones in between.

One of the reasons it makes the results difficult to evaluate is we have, as this slide indicates, a total of 54 cases; even though that seems like a lot, we have decided that there were some holes in there. And in my presentation later this morning you'll see that the way in which we ended up doing those evaluations has left us a little weak on the cost-impact side of things.

But nonetheless, there's a lot there. It's hard to try to sort of get your arms around it. And so some of the slides I'll run through this morning are an attempt to make those results seem -- sort of grapple with them and come to grips with what they are. And that, of course, is the purpose of the addendum report.

Chapter 3 of the main report tried, with some specificity, to lay out the metrics we're using in the analysis. It's always difficult in one of these studies to determine exactly what someone is analyzing, there can be so much there.

So we had a whole chapter trying to define precisely what we meant by various kinds of costs, for example.

Chapter 6 provided the sort of baseline or deterministic versions of each of the scenarios. A lot of sensitivity analysis of the consequences of different changes in assumptions around that. Still not as much as one might want, to really cover all those known uncertainties.

But the basic results are characterized by cost and by GHG emission reductions. And that's the main focus that I'm going to be using this morning.

So, this is a table -- and I hope everyone has a copy of the report or a copy of these Vugraphs close by. These numbers will be hard to read if the only thing you're using is the screen. But let me just lay out the basic organization of the table.

We have the nine scenarios as rows. And there are three sets of columns. There's a set of columns for California, the rest of WECC in the middle, and then total WECC, meaning the sum of the two, to the right.

Each of those three geographic areas has

two key variables: system costs in the year 2020 and GHG emissions in the year 2020. And a lot of the tables that I'll go through later in this presentation sort of build off of this sort of basic information.

And with this you can begin to see that there's some possibilities of tradeoffs. We have different levels of costs; we have different levels of predicted emissions for that year; we have California results; we have rest-of-WECC results. They don't always go in the same direction. And so inherent in this chart is a beginning of some kind of tradeoff assessment.

Let me just point out that one of the things we'll see throughout is that the energy efficiency costs are the scenario that is among the least costly. And that is a consequence, of course, of the assumptions that were used on the cost, not only of energy efficiency, itself, but all the other resources. But it's something to bear in mind.

While I'm focusing on costs, let me remind everyone the basic approach that we were, in effect, forced to use because of the timeframe of this study. All the technology costs were kept

constant except for rooftop solar PV, the California Solar Initiative cannot possibly happen unless costs come down from their current levels. And so we made an assumption that that technology would reduce its current cost by half out there in the 2015 timeframe.

The costs for the various technologies predominately come from the staff cost of generation project, which has been a subject of a workshop already in this IEPR proceeding. It was supplemented by some coal power analyses that come out of the Frontier Line effort.

Lots of studies have -- well, one of the consequences of that project, the cost of generation project, results were that costs were somewhat higher than the last time this analysis had been done. And that's consistent with many other studies.

In fact, there's an article in The Wall Street Journal apparently Friday or today, talking about wind technology and the problems of enough of them and the run-up in cost because of the limited production capacity that exists right now.

How those costs will change into the future is uncertain. But because of the timeframe

of the study we simply could not investigate alternative scenarios about technology costs. And that's probably the uncertainty that is most important, yet not yet investigated.

We also have some issues associated with the measure of costs. A lot of the tables in the report focus on the year 2020. And while that's a perfectly fine assessment of the consequences in that particular year of expenditures, it has some weaknesses. It suffers from what we're referring in the report to end effects. Meaning that there are some facilities and projects introduced near the end of the timeframe that have costs that go into the analysis, but they have many years more useful life beyond 2020.

And for those technologies that are expensed traditionally, like energy efficiency, that can, in fact, be a quite distorted view of their overall cost effectiveness.

Correspondingly, a year 2020 view doesn't account for the fact that there have been prior expenditures, and particularly for, again, like energy efficiency, that are expensed in the year of the introduction of the measure. they're still having a useful contribution, but there are

no costs being reported for them in the year 2020.

So, levelized costs over the years 2009 to 2020 is a better variable, but it's still imperfect. 2020, again, has this end effect issue levelizing attempts to only count a portion of those investments. But until such time as the analysis can be extended and we can be more sophisticated about tracking the pattern of costs through time, we'll always have some weaknesses.

So this is a chart that shifts, so that basically out is the same. We have scenarios as rows; we have three different regions as columns. Instead of total cost this is now a levelized cost on a per-unit basis.

And here the findings of the previous chart are not quite the same. In the previous chart energy efficiency looked the best. Here energy efficiency, on a per-unit basis, which is sort of in the center of the chart, is not looking so good. Actually current conditions is the least cost. So that implies that the increment of cost consequence of going to the more preferred cases, is a more obvious cost versus benefit tradeoff; benefit being the GHG reductions.

On the other hand, the change in the

renewables-oriented cases compared to the previous one is not as pronounced. There's only about a 10 percent cost penalty on a levelized cost basis. And so this is probably overall a better view of the cost consequences of the scenarios.

So here, just to reiterate what I was saying, the shaded yellow cells are the least cost in each of the two geographic regions. It's the current conditions case for both California and rest-of-WECC, and by extension, all of WECC.

The purple-shaded cells are the next two cheapest. I was going to do the cheapest, but since the numbers are almost exactly the same, I shaded two of them. So there's very little additional penalty, quote-unquote, by going to the high efficiency case, 3A, in California compared to case 1B. And remember that case 3A has all of the features of case 1B plus additional energy efficiency.

And that's the same construct for all of the additional scenarios. Using the more preferred resources, they all have at least the level of case 1B requirements. And so their consequences are incremental to case 1B.

Here I've added a shaded cell for what's

best for rest-of-WECC, which actually is the high renewables case.

So, attempting to put together some sense of cost effectiveness or cost/benefit of the various cases, this table takes the same GHG emission values from table 1.

Subtracts off case 1B so that these are the increments of each of the other cases, relative to case 1B, both in 2020 cost differences as well as 2020 emission differences.

And then the third column on the far right is sort of a measure of the cost effectiveness cost divided by GHG, both in the delta sense.

The addendum report has a couple paragraphs that makes note of the fact that energy efficiency, renewables and combined scenarios always are shown as cheaper for California when they're implemented westwide. And the reason for that is that there are import shifts between the cases.

So, for example, case 3B, which is the high efficiency case on a westwide basis, has the same energy efficiency assumptions in it for California as case 3A. So it's truly an

incremental scenario for the rest-of-WECC portion of the west.

Its overall costs show, and its costs per unit, ar a little bit less than for case 3A. And as chapter 7 of the main report talks about, that is the consequence of a shift in imports and a shift of essentially the carbon responsibility for California relative to the previous case.

And this issue of how imports will change as the resource mix changes through time, both resource mix within California and resource mix across the west, is an important issue that needs to be dealt with in concern with all of the other states. And particularly the states participating in the GHG emission reduction MOU are certainly a logical starting point for that kind of discussion.

Because they all have a broadly shared goal of GHG emission reductions, yet the interconnected system says there's a lot of interactions among them that need to be taken into account.

Turning to GHG emission reductions, themselves, those are reported in detail for all the scenarios in chapter 6 of the main report.

And we use two different perspectives in reporting those. The power plants located in California and subject to California regulation. And the idea of California responsibility; that is, again, the power plants located in California, but also the so-called remote power plants owned by California utilities, either in whole or shared ownership, that are located outside the state, and designed to serve California loads. And then, of course, the remainder of the imports that are short-term market purchases.

So those were the two perspectives that were reported in the report. I'm going to focus in this presentation more on the California results, as those are ones that policymakers in California can affect directly.

And that's what this chart does. This is a depiction of the same results shown in chapter 6 of the main report, and in the appendices in detail. Each of the scenarios is reported; some of them are actually on top of each other, so there's fewer apparent lines than the legend shows.

The top line in the dark blue is case 1, being the conventional buildout of the resource

mix with only weak levels of efficiency and renewables. And, of course, the one in brighter blue with the squares at the bottom is case 5B with high levels of efficiency and renewables.

And this is the case 5B, so this also in effect says that California is benefitting from high efficiency and high renewables in the rest-of-WECC. And there are higher levels of imports into California than are predicted in case 5A, which is the sort of lavender line, which is the next one above.

ASSOCIATE MEMBER GEESMAN: Mike, how did you derive the implied goal?

DR. JASKE: The implied goal, yes. Thank you, I was just about to say that. The AB-32 construct is that by 2020 California emissions get down to the 1990 level.

When I calculated, and what I say by implied goal of 43.36 million tons is going to the estimated emissions for 1990 of California power plants. So that is the value in the Energy Commission's inventory, which, I believe, the other agencies have agreed to use. And so that is what California power plants would be expected to get to if all the sectors had the same general

direction.

Of course, the analysis underway under CARB's leadership may well lead to differential requirements for each of the broad sectors. But we don't yet have that decision from them. And so this is applying that same concept just to the electricity sector.

ASSOCIATE MEMBER GEESMAN: So it's a proportionate contribution from the electric sector.

DR. JASKE: That's correct. All the proportional relationships that existed in 1990 would be assumed to be the same in 2020. And the real number out of that AB-32 implementation process could either be higher or lower.

Okay, sensitivity results. As I said at the outset, we did a lot of alternative runs. Some people have said we should have done more or different. But nonetheless, even as many as we did makes it difficult to sort of understand what those results are.

So we examined fuel prices. We did that in two ways. Looking just at the impact of production costs holding the resource mix constant. So, in effect, short run fuel price

perturbation. And then we also looked in case 2 at a change in the resource mix as a result of sustained high natural gas prices.

We looked at a sensitivity to hydroelectric generation, a major factor that would cause fossil plants to either produce more when hydro generation is down, or less when hydrogeneration is up. And getting a sense of that swing is, I think, an important factor for any AB-32 type regulatory regime to deal with.

And then we tried looking at some things on more of an operating scale, variations in load, variations in wind output as weather changes from day to day. That turned out not to be as interesting.

So what I'm going to do now is look at a similar slide as was constructed before. Again, the rows are the scenarios, the columns are the broad geographic areas. And I'm introducing, in addition to the baseline value in the center of each of the three sets of columns, the low natural gas result and high natural gas price result.

And so you can see in this particular variable is levelized costs, dollars per megawatt hour. You can see there's quite a swing in the

California values; something on the range of 10 to 15 percent up and down. Not quite as much swing on the rest-of-WECC. And, of course, their values are scaled further down, always lower than California. And WECC, as a whole, of course, is a blend of the two.

Now, there's, of course, another sensitivity that I mentioned a minute ago. There's the high hydro and the low hydro. So what this slide does is take the same row of three numbers and adds two more values, on in the upper row by itself, and one in the lower row by itself. So there's actually a cluster of five cells for each of the scenarios.

Here we're reporting California system costs in 2020 and California carbon emissions. And so you can begin to see, perhaps more clearly than in other of our formats, this degree to which the result can vary, given these two key sensitivities that we evaluated.

So, looking, for example, at case 3A, the high efficiency one, there's a total cost of 15.7 billion in that particular scenario. It can vary all the way down to 12.6 with low gas prices, or all the way up to 17.4 million with high gas

prices. There's a much narrower range in costs in the hydro swing.

Conversely, if you go to the cluster of five cells, immediately to the right under California carbon emissions for case 3A there's a baseline value of 60 -- I think these are million -- tons. Varies very little with high and low gas prices. Varies much more significantly with high and low hydro.

So, there's actually an opposite effect here. The high/low fuel prices affect costs significantly and emissions relatively little. Whereas hydro affects costs relatively little and emissions significantly.

This is the same format and the yellow highlighted cells are the highest value of the cluster. They always turn out for costs to be the high natural gas cost. Variant and for carbon emissions, they always turn out to be the low hydro circumstance.

MR. ST. MARIE: Michael, can I stop you for a second?

DR. JASKE: Yes.

MR. ST. MARIE: It's interesting to me that the low natural gas cost scenario results in

less carbon emissions than the high natural gas cost scenario. And I would think that people would be relying more on conventional generation in the case of low natural gas costs than high natural gas costs. Am I missing something?

That is, I would have thought the numbers would have been reversed between let's say case 3B in the far-right column between the 55,000 and the 54,000.

DR. JASKE: I think in that particular instance we're probably seeing, again, one of these non-intuitive consequences of imports. So, California has much higher proportion of its fleet with gas than rest-of-WECC --

MR. ST. MARIE: Actually, the example that I pointed out is in the direction that I expected. It was the one before it in 3A where I had 59 versus 60. Okay, and so I apologize for giving you the wrong numbers, but still your explanation is that it could be in the import scenario?

DR. JASKE: Yes, imports swing around quite a lot from one of these scenarios to the next for a given year of analysis.

And I think, as best we've been able to

discern the results ourselves, on the project team, it's these relative cost issues that the model is dispatching the least-cost plant.

MR. ST. MARIE: Thank you.

DR. JASKE: There are, of course, many additional uncertainties. Some of them we've been desirous of doing ourselves. Others, parties pointed out as far back as the January 29th workshop.

Some of them are amenable to quantitative evaluation of the same sort that we've done to date with fuel prices and shocks; and others are not. But perhaps can be examining qualitatively. So I want to just give some examples of that sort of qualitative assessment.

Again, using the same chart from before, the blue shading is the point of departure from what I'll get into. So, we had these results for the California high efficiency scenario. Generally the least cost of the ones the California policymakers can pursue, themselves.

Some significant GHG emission reductions compared to other cases. So, interesting to pursue, as that's something can hold up to all of the other uncertainties that we know to be out

there, but haven't yet analyzed.

So this table taken directly out of the addendum report attempts to just spin through some of the ways in which uncertainties could be evaluated.

So the first of those is a change in the administrative cost per unit of savings. We had certain assumptions. We could increase those, as is shown in the row 1A. And increasing those might well be a consequence of pushing harder to get higher levels of participation.

It takes more effort on the part of program administrators to get the next degree of participation. What would those results be for costs? Well, they would probably be higher total cost than what we had assumed in the baseline, assuming you had a particular savings goal that you were trying to achieve.

What would the implications of that be for emissions? Well, assuming you did actually achieve that same savings goal there wouldn't be any consequence for emissions. You would have the same physical result. It just took more dollars to get there.

Conversely, what if things are cheaper?

What if things are cheaper because we use a greater preponderance of mandatory programs as opposed to voluntary programs. Cheaper per unit of overhead, et cetera. So we would have lower total costs in that instance than the baseline. And, again, assuming we only went as far as achieving the same numeric target, there wouldn't be any consequences for power generation mix or GHG emissions.

All right, here's another one. The change in measured costs per unit of savings, as opposed to the administrative side of things, what about the technology, itself, is more or less costly. So, they could be more costly because there's higher engineering costs, higher physical costs of distributing the equipment, getting it installed.

What would that implication be for overall costs? Well, if you, in contrast to the first case, assumed that you only did this as far as your funding went, you wouldn't have any major changes in total costs; but you'd probably have fewer measures introduced; their savings would be less; you'd have to burn more gas, rely upon more fossil-based imports. And so there'd be a

decrease in the amount of GHG reductions.

Opposite case, 2B, things turn out to be more rosy. More effective equipment is available at a cheaper cost. Can be sent through distribution channels. Less costly than had been anticipated.

Again, if budgets guiding -- these program administrators are set up such that they only spend the amount of money that's been allocated, then they'd still spend that amount of money, yet the higher savings. You'd have therefore less fossil generation and increased GHG emissions.

So, it's the design of the program that is the key to how it is these uncertainties unfold in the real world.

How about a third uncertainty, the emerging potential that was taken from the ITRON study is achieved in a different way, using lower cost measures for higher cost ones. Total costs would go down, assuming you were being guided by your savings goals. But because you achieved those savings goals there wouldn't be any change in resource mix or fuel use, therefore GHG emissions would be largely unchanged from the

current scenario result. And conversely, the opposite.

So the point of this is just to say that how it is one designs a program, and to deal with the uncertainties that are there in energy efficiency measures and by extension, renewable programs and all of the other things that are elements of these broad scenarios can steer the results and are the kind of things that need to be done. Perhaps not in these instances in more analyses at this broad scenario level, but in thinking through how to design the program that would result, assuming you wanted to go in a direction of higher efficiency goals than have been directed to date.

And so that leads me to the last portion of my presentation, is given what we have found in the scenario project, how does it compare with the policy goals that already exist.

We, of course, have many preferred resource types that have numeric goals. Certainly for IOUs and emerging for publicly owned utilities. Some don't yet have a numeric goal even though there's a general preference for them.

We have related energy policy goals of

retirement, repowering and, of course, the over-arching AB-32 GHG emission reduction goal.

Table 6 of the addendum report attempts to portray for each of the California-oriented scenarios how we're doing relative to energy efficiency, rooftop solar PV, supply-side renewables and greenhouse gases.

And the basic result here is just to remind us that case 1B is sort of at the margin, satisfying the current requirements. Case 3A, the high efficiency one, exceeds the IOU goals as articulated to date. And I believe it exceeds what it is the POUs are putting forward in the AB-2021 process.

Doesn't yet satisfy the CSI. Does exceed the renewable portfolio standard if the higher energy efficiency is taken into account as a reduced electricity purchase on the part of end users; and therefore lesser renewable is required.

Conversely the high renewables case doesn't exceed energy efficiency, but does do so on rooftop PV and supply side. None of the ones so far achieve the implied AB-32 goal.

And then at the bottom row, even in the case 5A with both high efficiency and high

renewables, where we're exceeding all of the energy efficiency -- excuse me, the energy efficiency renewables and CSI goals, we're still not getting down to the GHG level implied, as shown in that chart.

So let me wind up with just a few key questions. Clearly we need feedback from other stakeholders about whether these results are credible, given other studies. Since energy efficiency renewables are the key levers, can they be pushed even higher than what's assumed in these scenarios. If they can be, at what cost.

Are we leaving something out that can contribute to power generation sector emission reductions. Clearly we're not tackling coal in rest-of-WECC, and therefore the degree to which coal contributes to California, through remote power plants or short-term market purchases, but since there aren't any coal plants directly in California, we're less able to affect those out-of-state coal plants than if they were located in the state.

So these are key questions that we enumerated in the addendum report. I think we'd like the stakeholders to give us input into, to

the extent they can.

ASSOCIATE MEMBER GEESMAN: On your first bullet on that last slide, did you have specific other studies in mind?

DR. JASKE: There is a study that the PUC did in late 2005 that was examining I believe it was a 33 percent renewable study. It seems, if I understand it, to have been at a one notch higher level of analysis than this. I don't think it used the production cost model as detailed as what we're doing.

There is, of course, the broad CDEAC effort from which we actually drew some of our assumptions for rest-of-WECC, but it did not do in-depth production costing or transmission load flow analyses.

So, I'm not sure that there actually are other studies trying to do the same thing. But sort of a general, let's see if there is anything out there that stakeholders know about.

And then, of course, as the report itself points out, because we're doing this analysis at a broad level, the physical level, we're not getting down into the individual load-serving entity. These results aren't directly

applicable to any particular load-serving entity who may have a whole different circumstance, just as an illustration. They could have more exposure to hydro or less exposure to hydro variation. So their circumstance could be quite different than these broad California-wide results.

And staff thinks that with at least some extensions, these results are useful in an overall assessment that the AB-32 design process should be taking into account, trying to identify where broad numbers of load-serving entities could go, assuming that California continues to use a load base perspective in its emission reduction strategies.

ASSOCIATE MEMBER GEESMAN: What extensions do you have in mind?

DR. JASKE: I think the whole issue of technology cost is one. And the second is we could do some work on either implied valuation of coal-based carbon, or in some sort of tax structures to determine whether and to what extent those kind of values could actually get coal down to the point, or its price up to the point where its dispatch is being affected.

Right now all the levels of analysis

coal plants are essentially operating the same. They're just humming along. Everything else is riding on top of them, so to speak.

And that's a critique that was made back at the January 29th workshop, and is valid. And I think it's amenable to some degree of analysis.

Okay, that's all I have.

(Pause.)

DR. JASKE: I guess I wanted to draw your attention, and also all the participants at today's workshop, to the questions posed by the Committee. There are about 11 of them. I'm hoping that either in the critiques that other parties will be making, as the next item on our agenda, or in the panel discussion that will follow that, that we can get some initial feedback on some of these questions.

I think these are the kind of questions that we need to be paying attention to; and if can't sort of make a full resolution of these today, as Lorraine said, the workshop comments that are due on July 20th is probably the next place to try to bring some degree of closure to these.

We could pursue them further at the

August 16th workshop, but that's beginning to get kind of late to provide input to you for your development of a Committee IEPR draft.

So, that's all I have to say in my comments this morning. Are there questions from the Committee?

PRESIDING MEMBER PFANNENSTIEL: Questions from the dais? Maybe we can ask Mike whether people here want to respond directly now to the list of questions that were posed with the workshop notice. And if not, I think we can go into the comments, any additional comments that people want to offer.

DR. JASKE: Okay, I know there are at least several parties who have told me orally that they're willing to make comment, so I guess they should jus decide what order to appear, and step up to the microphone.

PRESIDING MEMBER PFANNENSTIEL: Sure. Anybody who has comments come on up to the mike here and identify yourself for the record.

MR. SEZGEN: Good morning; this is Osman Sezgen from PG&E. I have some general comments. The report analyzes the impacts of high levels of participation of penetration of energy --

renewables, and is very useful and informative for motivating policy discussions related to these two resources.

Proposed policies need to be evaluated concerning impacts of these policies on at least four key metrics: Reliability, cost, environmental impacts and rate stability. And this report here goes a long way in showing impacts on all four of these areas.

However, to facilitate a more comprehensive discussion of policies such as AB-32 compliance, there's a need to look at broader range of resources together with energy efficiency and renewables.

The results of the study, for example, show that the cost of reducing CO2 emissions through renewable projects is in the range of $300 to $400 per ton. There may be other means, such as allowance purchases and offset projects that will reduce GHG at lower cost.

And the point here is there's a wide range of resources that could bring us to the same point. And in the future it would be very beneficial to incorporate those projects into the study.

Thank you.

PRESIDING MEMBER PFANNENSTIEL: Have you done a study that would do that?

MR. SEZGEN: We are working on constructing a supply curve for GHG reductions. We're in the process.

As you know, as part of AB-32 the targets for -- if there's a cap-and-trade system, the targets for California is not determined. And the targets for -- sectors are not determined, either.

So there may be sort of cheaper projects in terms of allowances elsewhere, not necessarily in the power sector in California. So, those, we think, should be part of this study when we're comparing the different resources to get to the same point.

PRESIDING MEMBER PFANNENSTIEL: So you're looking at possible purchase of allowances on the market?

MR. SEZGEN: That's correct.

PRESIDING MEMBER PFANNENSTIEL: And so that, of course the cost of those is unknowable at this point.

MR. SEZGEN: That's correct, at this

point. But future forecasts of carbon range from $10 to $50; and now we're seeing costs of $300 here, as reported here.

However, there are other benefits of renewables like hedging value. So, in a broader framework each policy could be -- has impacts on, again, the four metrics, the reliability costs, environmental impacts and rate stability.

So each one bring with it benefits and like for renewables, they do hedging, they have a hedging value. They have GHG reduction. But other projects may have different values for those four metrics.

And then we really have need to look all of them together and make a policy decision as to --

PRESIDING MEMBER PFANNENSTIEL: So it sounds like the analysis you're doing, constructing the supply curve, is similar to what Dr. Jaske has been showing us, with perhaps more variables.

MR. SEZGEN: That's correct. This work could feed into that --

PRESIDING MEMBER PFANNENSTIEL: So it is consistent with -- where are you in your process

in terms of developing that?

MR. SEZGEN: Just starting.

PRESIDING MEMBER PFANNENSTIEL: Thank you.

MR. SEZGEN: Sure.

ASSOCIATE MEMBER GEESMAN: Can I ask, do you get the $300 to $400 a ton figure from the report?

MR. SEZGEN: Yes.

ASSOCIATE MEMBER GEESMAN: That appears in the report somewhere? Or is it something you've derived?

MR. SEZGEN: No, this report here. It's on -- actually it's reported in one of the summary tables. And also you could look at like everybody meeting their requirements versus a renewable California case. And then look at the cost difference, and then the GHG difference, and just divide them.

ASSOCIATE MEMBER GEESMAN: And is that a ton permanently, or is that a ton per year number?

MR. SEZGEN: I believe it's ton per year.

DR. JASKE: That's an excellent question. I'm trying to figure it out on the

spot. The --

ASSOCIATE MEMBER GEESMAN: We can put it into the record later. I just wanted to make certain that we were doing an apples-to-apples comparison. Because the market estimates that you made, the $10 to $50 numbers are ton per year --

MR. SEZGEN: That's correct, it's ton per year.

ASSOCIATE MEMBER GEESMAN: Okay.

DR. JASKE: Yeah, I'm certain that the numbers we're reporting have qualities of multi-year to them. Quite how to think of them in that fashion bears some thought.

MR. SEZGEN: The cost for annual, I believe, would --

ASSOCIATE MEMBER GEESMAN: Thank you.

MS. JONES: Good morning. I'm Jacqueline Jones with Southern California Edison. And we want to thank the Commission and the CEC for the opportunity to comment on their work. Just a couple of general comments.

One is that we agree with the report and its recommendation for caution in the application of the results. We also agree with Dr. Jaske's comments earlier with respect to additional work

on the cost of the technologies that was used. We understand that it is, in fact, difficult to predict the future. But possibly more work in that area I think would help support the results.

Also agreeing with PG&E, we think that there may be more opportunities to reduce GHG emissions other than just increasing EE and renewables. The potential for clean hydrogen projects. Or we're also working on reduction, CO2 reduction actions in our AB-32 compliance studies at Edison.

And finally, we would like to work with the Commission on a collaborative process for making recommendations to be included in the IEPR so that it's a more unified representation of what we think is appropriate.

ASSOCIATE MEMBER GEESMAN: Can I ask if you expect you clean hydrogen efforts to show material impacts on CO2 by the 2020 time period?

MS. JONES: It's a little early to say. We're just in the study mode right now. So we're not really sure of any results just yet.

ASSOCIATE MEMBER GEESMAN: And beyond energy efficiency or renewables or clean hydrogen, what types of activities do you see contributing

to your CO2 reduction effort?

MS. JONES: Well, I know for the AB-32 voluntary early actions that they're working on, they're looking at a lot of different types of technologies, including distributed generation -- of course I can't think of any more right now. But there's several different areas that they're looking at with respect to reducing CO2 that seem to be likely to make significant reductions.

ASSOCIATE MEMBER GEESMAN: If you could send us a letter or something that identified those, it would be helpful to the development of our record.

MS. JONES: Okay.

ASSOCIATE MEMBER GEESMAN: I think, as Mike indicated, creating the scenarios required some fairly basic assumptions. But if there are key areas that we've missed, they certainly ought to be brought out in our record.

MS. JONES: Okay, we can include it in our comments.

ASSOCIATE MEMBER GEESMAN: Thanks very much.

PRESIDING MEMBER PFANNENSTIEL: And I notice the comments are due July 20th. And I

would be hoping that by then, which really isn't all that long from now, you'll be able to offer some specific concrete recommendations to the staff in terms of pulling together an analysis, doing whatever additional work is necessary to make this analysis something that is, in fact, something that Edison would buy into.

MS. JONES: We could do our best for that.

PRESIDING MEMBER PFANNENSTIEL: Okay, we'll look forward to the comments, then.

DR. FERGUSON: I brought some slides, if we can fire this thing up.

(Pause.)

DR. FERGUSON: Good morning, Madam Chair, Commissioners and colleagues. I'm Rich Ferguson, a Research Director at the Center for Energy Efficiency and Renewable Technologies.

I brought some slides with me today. I'll try to go pretty quickly through them. I apologize I don't have enough handouts for everybody. Sooner or later this will appear on our website, but for today you're just going to have to take notes, I'm afraid.

First, I should say that Mike and his

team have done an excellent job with this report. I'm not here to criticize their work at all. What I am worried about is sort of how we talk about this in the IEPR, and what conclusions we try to draw.

Because, in my opinion, there's a serious problem. And that has to do with the gas price estimates, the projections that went into the basecase results. I consider these estimates extraordinarily low. But I understand that no matter what projection you pick the future gas price is going to be different. And, you know, we have to figure out a way to deal with that.

But these gas prices are, indeed, passed through to the customers. And if whoever makes use of the IEPR report goes about preparing some sort of policy based on this report, and picks a scenario with an unrealistically low gas price, that hurts consumers.

But I have to admit that the Commission right now has no way to assess what the risk associated with any particular gas price forecast is.

So, my initial thought today was come down, as I have done every year now for many

years, and sort of criticize the equilibrium computer model gas price forecast. I decided not to do that. But then I realized if I were in your shoes I wouldn't know how to pick one over the other anyway.

So what I have today is another idea about maybe how we could go about sort of minimizing this risk. And that's the question I pose today. How can we minimize this potential risk to customers that these scenario choices involve because of the gas price risk.

And my answer -- first of all, I've got to really convince you that, indeed, there is a significant risk that the gas prices that were being used for the basecase are really too small. And then we'll talk about my scheme for solving that problem.

But the answer -- I'll just give you a clue now -- is that it might be useful for us to think how we would establish firm natural gas prices for use for these kinds of scenarios in the future. So we'll get back to that in a minute.

But I just have to point out since I've been coming here, this is the U.S. crude and natural gas future prices. These are nominal

dollars. The red is natural gas; the black is crude oil.

And as you can see they've increased mightily, some 300 percent, in the last decade. And these were unanticipated increases. You didn't see these in EIA forecast; you didn't see these in Energy Commission forecast.

Similarly, the EIA forecast is not forecasting price increases in the future. On the contrary they're forecasting significant decreases. Likewise for gas prices. And these are, I think, pretty close to the basecase gas prices that were used in the report.

And the EIA and IEA energy price projections are based on crude oil prices. And basically the standard dogma is that Saudi Arabia can and will keep the world supplied with enough crude oil to put prices back to $50 and keep them there forever. That's the sort of standard mantra that you hear about why we can use equilibrium models because there's always going to be plenty of oil supplied to the market. And then you can use your usual supply/demand curves and so on.

But, as Commissioner Geesman and I know well from our days on the Power Exchange Board,

markets aren't always in equilibrium. Sometimes they're disastrously out of equilibrium. And it's my contention that world crude oil markets are there today.

By the way, I got a phone call earlier this morning saying that today's, at least, online version of The Wall Street Journal has a comment from IEA expecting severe oil price problems this summer. I haven't seen the article yet, but I just key it up because who knows, maybe they're changing their mind.

Anyway, that assumption is risky. This is the list of the top 15 petroleum exporters in the world. And 13 of these countries the oil industry is owned by the national company. Only Norway and Canada are now privately owned corporations running them.

And as you can see, Saudi Arabia exported exactly as much in 2006 as they did in 2004. This is not a happy story.

This chart here is probably the scariest chart that I've seen in a long time. As you can see, the red is the three-month running average crude oil price. And, by the way, Brent Crude in London was trading yesterday above $77. So

there's still plenty of upside possibility here.

But notice that since May 2004 despite these very attractive prices, crude oil has flattened out; has not increased in three years. And one begins to wonder, okay, what kind of price is it going to take to loosen up that market and get more supply, if, indeed, it's at all possible.

To my mind anybody who ignores this shouldn't be in the energy policy business. For example, if you look at since January '03 you get a pretty nice parabolic curve that happened to peak at January 06. I don't know how you feel about the peak oil theories, but you've got to admit that they're looking pretty good right now.

The value of the dollar may continue to decline due to the U.S. trade deficit. This is what's happened to the dollar versus the Euro since January 02. A large part of our increase in oil costs has just come from this kind of phenomena. If I had drawn that last graph in Euros instead of dollars it would have looked quite different.

Of course, alternative projections are risky, too. The way I do projections is basically assume that changes that have been occurring in

the recent past are going to continue to exist in the future. Excel helps me, because Excel will just draw this nice straight line, the blue one, through your data. And, in fact, it'll even -- you can tell it how many months in the future you want to run it, and it'll give you that, too.

You know, if I just saw that data and said, hmm, what's going to happen in the future, I'd draw that blue line and say, hey, it might be something like that.

And then you could argue, well, it could go up, could it go down, whatever. But you have to do some pretty fancy footwork to imagine that the data with this kind of trend is all of a sudden going to turn down like that.

But this is the point that I started with, is from your point of view how are you in a position to say, well, let's use the blue line because that looks better than the black line. You know, you can fall back on, well, everybody's using the EIA projections for their basecases, so we'll use that, too. But, as I say, that completely ignores this risk.

You can build that into a sensitivity, but as we know, there's a nasty habit when we

release reports, that people tend to cite the basecase results and not the sensitivity results.

So, this is my point. We need to think a little bit about how the IEPR is going to talk about these results and these scenario choices; and especially the costs of the various scenario choices that he's run. Are you going to cite the basecase and sort of hope that somebody picks up on the sensitivity.

And I make this argument to the Legislature or wherever and they say, hmm, maybe we'd better use this high price gas sensitivity. In fact, the high price gas scenario they ran was well below that trend line.

And I don't know how you can answer that question. If I were a Commissioner, I wouldn't know how to answer that question, either.

So, the question is maybe we should think about how you would avoid having to answer this question. In other words, how can we minimize this gas price risk. The fact that we don't know what gas prices are going to be in the future.

And my answer is to try monetizing this risk. And include the cost of doing so in

electricity prices, or in your gas prices that are passed through to consumers.

In other words, in a good republican kind of spirit of things, we'll say, well, we'll let the market decide what the risk is associated with any particular gas price scenario.

So basically what you do would be to pick a scenario. You could use EIA, you could use a trend, you could dream up something else; and then you go to Wall Street and say, okay, what would it cost for me, or California to guarantee those prices. And then we take our price estimate, add on the cost of the guarantees and that would be the net sort of monetized risk-free cost gas price projections to consumers.

And it wouldn't matter then which -- it wouldn't matter much anyway -- which gas price scenario you chose. If it was one that was pretty close to whatever Wall Street thinks is going to happen, then it would be cheap. If you pick something that they're going to have to have -- a high probability they're going to have to cough up some dough, then it's going to be more expensive and so on.

But it would be a way of trying to get a

firm, long-term gas price that you could use and avoid this problem that you've got.

ASSOCIATE MEMBER GEESMAN: What if there are no bids?

DR. FERGUSON: Well, that's a good question. I don't know. What I was worrying about is how do you analyze the bids.

ASSOCIATE MEMBER GEESMAN: You can look at a screen and, you know, there's some liquidity in the bid out to about two years on NYMEX. There's a nominal price that you can carry out to about five years. But bring me a bid at ten years. Bring me a bid at 20 years.

DR. FERGUSON: Well, and even -- you couldn't really do that. I mean the long-term futures market is a strange kind of market. I happened to look up how many trades there were in the January contract on Friday, and there was exactly one.

It's not a real robust market. So, --

ASSOCIATE MEMBER GEESMAN: What's that tell you?

DR. FERGUSON: It tells me that there aren't very many people trading --

ASSOCIATE MEMBER GEESMAN: Why is that?

DR. FERGUSON: -- out that far. Well, that's a good question. I don't know the answer to that. Except that --

ASSOCIATE MEMBER GEESMAN: What's the message we should derive from that?

DR. FERGUSON: The speculators aren't interested in the long term, I think, is --

ASSOCIATE MEMBER GEESMAN: Doesn't sound like anybody is.

DR. FERGUSON: Well, -- okay. Most of what NYMEX contracts are traded for, ar financial contracts. And there's very little oil on it actually.

ASSOCIATE MEMBER GEESMAN: Yeah, but there are people that do have your viewpoint. You know, Simmons is developing an entire book-publishing career out of his peak oil theory.

DR. FERGUSON: Yeah.

ASSOCIATE MEMBER GEESMAN: Yet there is no one in worldwide capitalism willing to put money behind that over an extended period of time.

DR. FERGUSON: Well, would they be willing to put -- actually I was hoping we could sort of get into this discussion, because it is a discussion that we're used to having. In fact, I

have a proposal for how we go about, and trying to see if you could do this or not.

But, actually Simmons is interested, and I'm glad you mentioned it, I have it in my notes and I skipped over it. But, if you want sort of the best analysis of the Saudi oil situation from somebody who has spent a bunch of time looking at it from a fairly sophisticated point of view, you really should read Twilight in the Desert by Matt Simmons, which is what he's referring to.

He's not really one of the peak oil fans, actually. There's some other people that are more into that. But it does raise this whole question about how long, you know, whether the Saudis are telling the truth when they say, well, you know, we could bump up our production to 12 million barrels a day tomorrow if we felt like it. He does not think that that's true.

I don't know the answer, John, whether or not you could get a bid or not. That would be interesting.

I talked to the fuel cell guys and they're having a hard time selling their things without a firm gas contract. So I asked them, well, you know, what are you getting for ten-year

gas prices. And he says, well, you can find some at like 850 or something like that.

I don't know what the creditworthiness of those people are. And if you're really sort of thinking about, you know, the creditworthy bid, then I don't know whether you'd get any or not.

But --

ASSOCIATE MEMBER GEESMAN: It strikes me, though, every time we approve a new gas plant, we're making that bet.

DR. FERGUSON: Exactly. That's my point exactly. You're exactly right. I mean we're living with this risk. And we haven't, in the last ten years anyway, we haven't done a very good job of anticipating how severe that might be.

Now, you know, if I were a Commissioner ten years ago, I'm not quite sure what I would have done, had I known that price was going to go up 300 percent. But I hope I would have done something. Something different, better than what we did do.

ASSOCIATE MEMBER GEESMAN: Well, let me explore, though, the flip side of that. Because I was here 25 years ago. And, you know, we didn't have any crystal ball as to what the price

projection should be. And as a consequence, in the Commission's 1982 biennial report we used the Delphi technique in developing an oil price forecast. Averaged all of the ones that we felt were professionally reputable.

As a matter of fact it turned out to replicate Chevron's oil price projections quite precisely, which raised questions as to what they paid for their forecaster.

But we projected --

DR. FERGUSON: Shell was doing some of that, too.

ASSOCIATE MEMBER GEESMAN: We projected oil prices to be at about $100 a barrel in 1982 dollars in the year 2000. And in the early and mid 1980s state policy was based upon that. There are a lot of people that would tell you that that led to the QF contracts that created a financial overhang, et cetera, et cetera, et cetera.

But there's a downside risk to price volatility, as well. And I can assure you in 1982 people spoke with the same level of certainty about prices headed in one direction that you're speaking today.

DR. FERGUSON: Well, may I be the first

one to admit that, you know, prices go up, prices go down. But it is interesting though, that was an area where the oil supply had recently been constricted for political reasons. And there's no indicate that that's going on today.

In fact, quite the opposite; but all the politicians are saying, no, you know, we're happy to deal with the oil -- so, it looks to me like bending over the oil supply curve really is demand destruction by high prices that we're beginning to see.

And, of course, that's what you expect, you know, whenever oil does peak and start to decline, it's going to decline because it's too expensive for most people to buy. So, --

ASSOCIATE MEMBER GEESMAN: I would suggest --

DR. FERGUSON: -- you do expect that to happen in a period of high prices. But there really is a significant difference, I think, from what was happening in 1980 and what's happening today.

ASSOCIATE MEMBER GEESMAN: I would suggest to you that volatility is a more dangerous enemy than level.

DR. FERGUSON: I'm not sure my -- well, that's true for some people. But it's certainly -- anyway, I don't want to get into that.

But the question is, you know, how are we going to deal with this. And in particular the problem you've got is how are you going to talk about these. Are you really going to, you know, throw out that cost even for the continued business-as-usual number-one scenario, 1A, or whatever it was called, using those locations.

I mean, people look at that and they say, hey, this looks pretty cheap; why don't we just keep doing what we're doing.

And, you know, if you believe the EIA forecast then that's what you get. And I don't think it's enough to sort of put that number out there and say, well, you know, there's a lot of risk in the gas price forecast, and so, you know, it probably won't turn out like that.

But, that's what worries me more. He's done an excellent technical job. There's no -- it's going to be a long time before I'm going to be willing to take a test on that report of his.

But what I'm wondering is how are we

going to talk about this, the results of that in a way that makes sense to other people that have to make policy decisions. And to my mind, this is the main factor that we've got to struggle with.

So, anyway, to make a long story short, actually I'm more worried about whether or not these insurance policies really cover the financial health of the utilities. And we had some experience back with the deregulation, as you recall. And, you know, you don't want a price that either bankrupts the utilities, or on the other hand, you know, they come back and win another couple hundred billion dollars or so.

So there's a lot of questions about how you'd actually go about trying to establish a firm price that you would use in rates, and let somebody else absorb all this risk, even if you could do it in --

ASSOCIATE MEMBER GEESMAN: Yeah, but with fuel cost pass-throughs, why do they care?

DR. FERGUSON: Well, they don't. It would have to be done by regulation. You're absolutely right.

ASSOCIATE MEMBER GEESMAN: But, again, to me that's a message, as well, as not being able

to get a bid past five years when you've got fuel cost pass-throughs, the utilities are indifferent, arguably the regulatory system is indifferent. Seems to me that we've built hazard upon hazard.

DR. FERGUSON: Exactly. There's no doubt about it. The gas price is going to get passed through one way or the other. The question is are you going to have a known gas price pass-through or just open-ended risk.

But I mean I'm not suggesting that the utilities keep that risk, either. That would be foolish. They need to get that risk passed off and redistributed through reinsurance and all that kind of stuff.

And I don't know whether you could do it or not. It would be interesting to find out what people consider the risk to be.

Anyway, I sympathize. I don't know how you can talk about these reports, the results of these reports and these various scenario costs without struggling with this issue and deciding what you're going to say about it.

I strongly recommend you don't just dump the basecase results and say, oh, yeah, well, if we had sustained high gas prices it would be

different. And make people do the subtraction and so on. I really do think you need to think kind of hard about how you're going to deal with that issue.

And, I mean for my purposes, if you wanted to think about what would it take, or could you establish a firm gas price for electric utilities, it would be useful to have a joint workshop on that, and bring some of the players, the Wall Street players, and see what you could get out.

If you could, you know, I would really love to see -- price. I would really love to see it. You know, and if you could do it, then, you know, then it's reasonable to think about requirements.

But, anyway, I'm afraid I haven't made your life any simpler, but I really think this is an important thing to think about. And it's got me worried silly. Like I say, that chart where you have continued high prices with no political or no apparent political decision to reduce supply, is a bothersome kind of chart.

So, we'll see where it goes. It could obviously turn up, and I'm the first one to admit

that it could. But, anyway, that's my contribution for --

ASSOCIATE MEMBER GEESMAN: You would overlook downside price risk because you don't think that's going to happen?

DR. FERGUSON: No. I thought about that. I think whoever's going to absorb the upside risk has to be able to balance that off against whatever downside risk there is.

ASSOCIATE MEMBER GEESMAN: What do you think of the Black Shoals capital asset pricing model as an approach?

DR. FERGUSON: You know, I was just looking at Black Shoals model, trying to understand it the other day. Unfortunately, that's based -- I mean it's an option pricing model and it's based on the fact that you know, or you can hold the underlying asset.

And I couldn't figure out what happens when the underlying asset is so difficult to know. So I'm not an economist, and you're way ahead of me. But, I don't think that volatility -- the current volatility tells a little story about the future. I mean there's always a theory that, you know, the market players have fully built in every

possible future and made their assessment. I don't think that's true, actually.

I think the market is very short-term oriented, and I don't think anybody's looking out to 2020. But --

ASSOCIATE MEMBER GEESMAN: If you're looking at long-term investments, isn't historical volatility perhaps a good indication of future volatility?

DR. FERGUSON: You know, I just don't know. I don't know the answer to that. You'll have to ask some economist. I think we're entering a different kind of world, and I don't know how to deal with it.

And I know you've been there 25 years ago, and you've seen it all. But I really think things are in a different place than they were then.

Anyway, thank you for your patience.

PRESIDING MEMBER PFANNENSTIEL: Thank you, Rich. Further comments, discussion?

MR. WANLESS: This is Eric Wanless with the Natural Resources Defense Council. I have a couple comments, and I think I'm going to probably save some of what I have to say for the

discussion, which I think is happening after this.

But, in terms of looking at the scenario analysis results, I just want to bring up again some points that we made in our comments.

The first one I guess I'd like to say, I'm glad that Mike was presenting some stuff here today in terms of total cost in addition to the unit costs. I think it's very important when we're thinking about what we're presenting to people in the IEPR that we place a very high importance on total system cost, so it doesn't look like renewables are more expensive in terms of what you're actually getting for your buck.

If you're not taking into account the energy savings of course it's going to look -- or excuse me, renewables and efficiency, efficiency particularly. If you're not taking into account the energy savings, then of course it's going to look more expensive if you're investing more and not taking into account the energy reductions.

So I think in terms of couching how we're presenting the results from this in the IEPR it's very important that play a pivotal role in terms of the cost impacts.

Some other things that we brought up in

our comments, and I think that looking at the power plant retirement analysis that was being talked about a little bit earlier today, is making sure that when we're presenting these different scenarios that we're presenting them on an equal footing.

And I know that in looking at some of the reserve margins for the different scenarios some of the high renewables cases had much higher reserve margins, which makes it difficult to compare things on an apples-to-apples basis.

And then I guess the --

ASSOCIATE MEMBER GEESMAN: We went into that in quite a bit of detail in the last workshop, and I think we're going to have to wait to see Mike's next rendition to know exactly how the group has addressed that.

But I think as you pointed out at the last workshop, that's a real area for concern. A nd the extent to which future investment in new coal plants in the west going forward is embedded into that type of modeling effort, it's also a cause for concern. And I think it's reflected in the buildup of reserve margins.

MR. WANLESS: And then the final quick

note that I've made before and that I'll probably talk about a little bit more as this discussion continues, is I think especially in the AB-32 context, it's very important that we represent a carbon cost in these results.

And I know that if it's not probable that they can feed into kind of the dispatch of different resources in the models that were used to generate these scenarios.

But I think presenting a low, medium and high carbon cost that reflects the fact that Californians are valuing a lower greenhouse gas emissions in terms of global warming, I think it's very important that in presenting this to policymakers, we give some sense of, okay, if you have, you know, low carbon costs, this is what the total system cost is going to be. If you have high carbon costs, this is what it's going to be, in terms of presenting a more complete picture of total system costs.

Thank you.

PRESIDING MEMBER PFANNENSTIEL: Are there specific comments?

Then I understand, Mike, you had planned to convene -- is it a panel -- on the questions of

the usefulness of the project results?

DR. JASKE: Yes, ma'am. So anyone who's willing to participate in that panel, come on up to the microphones.

(Pause.)

DR. JASKE: So I think before we get into the specific questions that were posed, I guess I think it would be helpful to start with this basic issue of this study, you know, being done at this broad physical level, is not the same study that an individual load-serving entity would conduct. Yet this may have value to a load-serving entity in sort of giving sort of background information; or to CARB in, you know, sort of helping do sector-by-sector tradeoffs.

So, I guess a basic question I have maybe in particular for utility people who are here is, is that correct; and how would you say, you know, describe the usefulness of this kind of study versus the things that you are doing, yourself.

So, --

MR. SEZGEN: I guess I'm --

DR. JASKE: Well, and we also have another rep.

MR. MINICK: Good morning; my name's Mark Minick from Southern California Edison Company. And I've known Mike a long time. Mike knows that I'm a production simulation modeler. My title is Manager of Generation Resource Planning.

I haven't been doing it quite as long as John, but I was involved a little bit in the forecast in 1982.

Regarding this particular study, I sort of applaud you for attempting it. It's very very difficult to do. It will give you general trends. But as we've said before, we have to look at more than just trends to see if we're going to build a system that's totally operable.

And the one thing this study can't do, because we use the same production tools that you're using, is assess the operability and some of the transmission limitations when we do the particular study.

And so if you're going to look at penetration of renewables first you have to look at what you're doing and try to assess what are the costs associated with these levels of penetration and protections and total costs. And

total costs have to include all the costs of buying these resources and transporting these resources to the places where they have to go.

The transportation, to me, is the most difficult to assess right now. You have to look at transmission costs -- we're having a real difficult time getting transmission lines built -- and the associated costs with getting those transmission lines built.

And then take a look after you've assessed the location for the new renewables, the penetrations that you can achieve in these new areas of renewables, transporting that power to the local load where it basically has to go. In most cases the load is many many miles from where the renewables are being built.

Then you have to assess the operability of this particular case. And you have to do significant transmission studies to make sure you've built the appropriate transmission.

My biggest fear is we can get it from eastern Sierras to the northern part of our service territory, but then to distribute it amongst our customers we have to upgrade many many pieces of our existing transmission to get it

there.

The other thing that we don't do well yet, and I -- we don't do it well yet, is basically assess the reliability of these particular cases. I know you've talked about the reserve margins being higher. Well, I've been doing reserve margin planning since 1980, and I truly believe that as we get more intermittent resources that we cannot predict their exact output on a daily or hourly basis. We're going to have to have more reserves to cover some contingencies that can occur in these instances.

And so I truly believe we will have to have higher reserve margins. And the fact that we will have higher reserve margins has to be considered as part of the implementation of more renewables.

In simple terms, if you have more wind you may need more peakers that are used on a daily basis in some cases to cover for the wind. Those costs are basically attached to that particular scenario.

PRESIDING MEMBER PFANNENSTIEL: Mike, did you include anything like that in the IE renewable scenario?

DR. JASKE: We were moving in that direction in two respects. First, we only gave wind capacity credit, sort of commensurate with the formulas that the PUC has been using in resource adequacy.

And that differs in the various wind zones within California. But it's on the range of 25 or 30 percent.

And so, in effect, we also then added a significant number of combustion turbines for precisely the point that Mark is making.

And those costs are added into the total cost. We haven't attempted to sort of isolate out the portion of those costs which sort of can be traced back to the various renewable technologies. But theoretically that could be done.

And when we did the stochastic analysis we were attempting to understand the degree to which sort of variation in wind production profiles could affect the viability of the system. That was the whole point of doing those stochastic analyses, to look precisely for this reliability issue.

It didn't pan out the way we anticipated

because -- and maybe it's because, you know, by imposing this sort of pseudo-resource-adequacy framework we actually had enough combustion turbines to prevent problems from appearing.

But I think that generally I would agree that those points that Mark's making are ones that need to be taken into account. And how to do it well, and how to do it, you know, in a detailed enough way to be sure you really, you know, have got a bead on things, is the question.

ASSOCIATE MEMBER GEESMAN: What about buildout of the transmission system?

DR. JASKE: Well, that's precisely what we're going to be getting into in more detail in this aging power plant trailer documentation that I've been mentioned at the last two workshops.

We are struggling, in effect, to do precisely what Mark's mentioning, is where we have the case 4A high renewables, you know, what does that actually mean about transmission system upgrades. Not only the obvious, you know, Tehachapi, buildout, but other aspects of their system that need reinforcement when sort of everything's coming from that direction; and it's got these intermittent qualities to it.

MR. MINICK: And we'd love to work with you on this. It's very complex. He's done a good job. But, as Mike knows, the model that we're using, and we use the same model, doesn't pick up intermittency very much. You put in a schedule for wind; it can be whatever you think might show up. But you can't vary it hourly in the model right now.

And we've been trying for years to try to figure out to sort of pick up some of this intermittency in the production simulation. But once the model knows what the output looks like, it dispatches around it. If something else were to occur, you would have a different dispatch. And we're not sure how to pick --

PRESIDING MEMBER PFANNENSTIEL: So, is your view then that the model is useful in a general sense, but would not be useful for, you know, day-to-day specific dispatch? I'm trying to calibrate how useful you think it is, and where the results -- are they useful for policy direction, but not operation, or not utility operations?

MR. MINICK: Yeah, it's not an operational model. It isn't --

PRESIDING MEMBER PFANNENSTIEL: Right.

MR. MINICK: -- a dispatch model. In general, it's going to give you the trends that you see. It'll show you general emissions; it'll show you general costs. But before you sort of go that direction, we, as a utility, and I think you, as a regulator, need to know am I building a system that truly will operate. My customers are my most important thing.

And also I don't know if you've looked at it, and we haven't looked at it yet, is the reliability of the system when you build it. Unsuspected unserved energy when you have this system; is it going to cause more chances of having outages over the long term, or less.

I mean we are very dedicated to meeting the greenhouse gas emission levels. Edison is trying to get there any way possible. As previously mentioned, we have lots of things we're looking at that are alternative to renewables that we'd be glad to propose in the future.

But we want to make sure when we build this system and get there, it truly does operate.

DR. JASKE: Let me just add that we're probably no more than a couple weeks away from

having some initial results. And so we're intending on sharing those with Edison. We already had one discussion with them about some details of their transmission system that we needed to get a determination from them to help do our work.

So I'm very hopeful that we will bring forward a product, at least as the next step down this path Mark's mentioning, and be able to at least shed some more light on the issues, if not resolve it all by the August 16th workshop.

MR. SEZGEN: This is Osman Sezgen from PG&E, again. My colleague here talked about some of the concerns we had which included operability of the system and reliability.

Also, we had concerns about uncertainty of renewables costs and energy efficiency-related certainties. And Dr. Jaske mentioned those in his talk.

I guess I will compare the study to the methodologies we use at PG&E in planning; and maybe mention that it would be useful for us if a similar framework was looked at at CEC.

What we do at PG&E is we try to define states of the world where we don't have much

control on, and then propose plans and test each plan under each scenario. And look at our metrics, which I mentioned before, the cost, the environmental impacts, rate stability and reliability.

In the framework presented here, for example, the policy which is high rates of penetration of energy efficiency and renewables, could be tested under different worlds, like you could say rest of the west does it or not. And also things like cost of renewables could be included, putting together states of the world, consistent states of the world where the gas prices, the rest of the west, and renewables prices all is constructed single state or different states. And then each of your policies are tested under those. And looking at the four metrics, or more.

And then you can weigh the tradeoffs between is this policy better or the other, because you have at least four metrics to evaluate against those states of the world. And it's up to the policymakers and the consumers to decide what the tradeoff should be. Do you want a risky low cost, or riskless high cost choice. Do you want

more renewables or would you -- you wouldn't mind having offsets elsewhere.

And it's a policy choice. But at least you have these metrics to look at and compare different alternatives.

Thank you.

ASSOCIATE MEMBER GEESMAN: In your experience in the utility industry, which end of that risk spectrum do you think that the industry should be at?

MR. SEZGEN: In terms of taking --

ASSOCIATE MEMBER GEESMAN: Taking the customers' interest into account, because the customers' interest ultimately translates into the shareholders' interest.

MR. SEZGEN: Right. We can hedge only certain sort of periods and then the Commission, the CPUC, determines how much hedging we can put in. Of course, we can put in more renewables in there, or other resources that could hedge that.

And we're looking at all those and trying to, like Dr. Jaske's team did, try to quantify the hedging effects of these actions.

In terms of what the consumer wants, I think there's this one-cent rate risk out there

that the Commission is, the CPUC is sort of, I'm not sure but there's either indicated or there's this one-cent issue, so that's -- again, also I think there are studies as to what that should really be.

ASSOCIATE MEMBER GEESMAN: Consumer's pretty risk averse, wouldn't you say?

MR. SEZGEN: Excuse me?

ASSOCIATE MEMBER GEESMAN: The consumer is pretty risk averse, wouldn't you say?

MR. SEZGEN: I would think so.

ASSOCIATE MEMBER GEESMAN: And not just in the utility area, but you look back over the tradeoff between fixed rate mortgages and variable rate mortgages; at no point over the last 30 years has the fixed rate proven to be the economically prudent choice. But overwhelmingly consumers have a preference for the fixed rate.

I think the same probably holds true on the utility side; that there's a pretty substantial apprehension about risk on the part of both your customers and your industry, at least based on what I read.

MR. SEZGEN: That's right.

DR. JASKE: Part of what the -- rep is

saying to us is we probably could benefit from repackaging this analysis a bit more into the formality of a portfolio assessment framework. And we've become aware of that moreso, as that staff project evolves sort of in parallel to this one.

In fact, we've even thought about whether it's feasible to take these results and formally put them into that framework. We probably would have to conduct several additional sort of dimensions of uncertainty to do that. And certainly technology cost is the obvious one.

Whether that is conceptually appropriate, which I suspect it is, but not numerically feasible in the timeframe we have of this IEPR, and has to be the sort of thing we might shoot for for a future IEPR. That's, I think, unfortunately where we probably are.

ASSOCIATE MEMBER GEESMAN: Commissioner Pfannenstiel was telling me just the other day how much she's looking forward to the 2009 IEPR --

(Laughter.)

PRESIDING MEMBER PFANNENSTIEL: I can count to five, John, --

DR. JASKE: Do any other gentlemen have

something to add on this one basic question?

MR. WANLESS: I guess I have a question maybe for the utilities is in the scenario analysis work how helpful would it be to, I guess, have a scenario that meets a proxy AB-32 requirement for the utilities. Is that something that would be valuable?

MR. MINICK: Could you explain what you meant by a scenario? A scenario created by the CEC that attempts to meet what you think our AB-32 requirements are?

MR. WANLESS: Right. I don't want to say there are any requirements on the utilities as of yet, but in terms of having none of the scenarios get down to proportional reduction in the utilities in terms of greenhouse gas emissions, would it be helpful to have a scenario that kind of benchmarks what that would look like, getting to something that's a proxy for what may end up being some form of reductions requirements on the utilities in terms of greenhouse gases.

MR. MINICK: It might be helpful, but I don't know if Mike has divided up the renewables by LSE. In other words, I think what they've done is taken and included enough renewables to get to

some target. I don't know how they've divvied up those renewables by LSE and the costs associated with them.

And right now, one of my other comments about the costs that they're using, because I don't want to give our confidential -- let us simply say that the costs you're using for some of those renewables aren't the costs we're seeing and some of the bids that we're seeing. There's a significant difference.

So I don't want to be misleading and have them divvy up these renewables by LSE. And then, even at that point, the costs may still be less than some of the bids we're seeing. And so I don't know how useful it would be to kind of have the CEC come up with a conclusion that might be skewed significantly from what we're seeing.

It might be better for us to say, okay, if we went this route, and we have a 33 percent scenario in some of the stuff we file with the PUC, to give the Commission some general information about how we see those costs associated with our own data.

DR. JASKE: Well, Eric, do I understand your -- the way I understood your question was

just assume, at least some people out there assume the electricity sector, you know, can do all these magical things. And so it ought to at least be able to, in the aggregate, get to or exceed the broad AB-32 reduction, which we haven't gotten to yet so far, even satisfy, let alone exceeding it.

So what more might it take to get there? I understood that to be your question.

MR. WANLESS: Yeah, that was certainly part of it. But I guess I was just curious to see, rather than pushing on you to do a lot of additional stuff to get a scenario that kind of gets down further than what we have now, whether that would be useful to the utilities.

I think it would be useful for NRDC in terms of just kind of having more information out there as to how that might look. But I was curious if that would be helpful for the utilities, as well.

ASSOCIATE MEMBER GEESMAN: Just to be clear that I understand Mark's comment, my impression that we're using cost of generation study prices for the renewable assumptions; and if I recall correctly, at least on the solar side, in particular, the cost of generation study's numbers

were pretty significantly higher than the contracts you've signed with Sterling Solar.

So I'm not certain that all goes in one direction as you imply.

MR. MINICK: That might be the case for that particular technology, but let's just say some of the other technologies, wind, geothermal and others, when I looked at the numbers that we have in there, and I just recently did it, and took a quick look because our group is the one that analyzes some of the bids, there was some discrepancies that bothered me a little.

And I'm also concerned, being an engineer by training, that I think the projects that are being developed first are the most cost effective. And as we continue to push renewables we'll be getting to less and less cost effective renewables, or wind regimes that aren't as good as the current wind regimes, which might raise the costs further.

And as Mike said, right now there's a shortage of turbines. If we continue to push and want more and more wind turbines, that usually just leads to higher and higher prices for the wind turbines.

And so we need to think about how we might do this in a more orderly fashion or something, and not perturbate the market so much that we end up buying all these really expensive wind turbines now; and if we would have waited three years they would have been 20 percent cheaper.

MR. SEZGEN: I was just going to mention that to push the envelope for meeting AB-32 just with the resources here, as Mike already mentioned, you have to build a supply curve because of the availability and the cost will vary as how much of that resource you take in.

DR. FERGUSON: Since we're on the issue of the AB-32 type scenarios, I was a little surprised, Mike, that you were looking at the carbon emissions from only instate plants. I mean with the -- what's the bill number - SB-1368 and the issue of, you know, buying power from out-of-state coal plants, I think most people -- well, I shouldn't say that -- a lot of people I talk to count the carbon emissions associated with imports toward the total.

And a lot of what I think people are talking about in terms of, you know, overall

greenhouse gas reductions have to do with the idea that we're going to stop buying so much out-of-state coal.

I think it would be at least useful to, in your various scenarios, to add another column where you're looking at the carbon emissions associated with imports much like they did in the sources -- report.

My guess is that that last scenario -- well, I don't know how you treated the whole coal issue, but I think it would be useful to sort of -- to look at the, and add in, or at least have a separate column for what's happening to imports emissions. Is that possible?

DR. JASKE: Yeah, we actually reported it that way as the main style of emphasis in the main report. It was for this presentation I decided to focus on the California part. And, yes, the imports do play a key role. And unfortunately, how precisely one wants to attribute the carbon emissions to the imports, you know, very much affects those results, given --

DR. FERGUSON: Well, certainly the remote plants.

DR. JASKE: Well, the remote plants is

pretty straightforward. And ought not really to be an issue. How to come up with carbon profile for short-term market purchases is a much bigger challenge. A lot of things have evolved in the AB-32 sort of implementation process, various agencies. In the very same time this project's been underway. And we weren't able to sort of keep up with all of that minutiae.

But presumably we can try to repackage our results to be consistent with whatever the current thinking is about how to treat imports.

DR. FERGUSON: It is kind of odd that electricity seems to be the only thing that we import that we do try to keep track of. I was thinking of all the carbon emissions we've shipped off to China in the last decade or so, nobody says a word about that. We blame the Chinese for those.

But, you know, for some reason or another we do want to count emissions associated with electricity imports.

DR. JASKE: I guess one -- another angle on this overall usefulness question is, is there something in particular that's missing from the project as it exists right now that if that

particular aspect were redone or added, you know, would sort of magically make it turn the corner and be, you know, of significantly more interest. Either from utility-perspective guys or from the environmental community.

MR. WANLESS: I guess with that my question is -- my reading of the report led me to believe that the existing policies like SB-1368 weren't necessarily constraints where the resource imports were not constrained by the emissions standard that's in place in California.

And also that things like the Governor's goal for 33 percent RPS by 2020 weren't necessarily used as constraints.

To the effect that I think that there can be a scenario, or to have some way before we ask is this useful in determining whether or not existing policies are effective, I think we need to have a scenario that achieves the existing policies that are in place.

And I guess to get at the AB-32 side of that, as well, as I've been saying a lot lately, I think that there needs to be a cost of carbon included in the results presented for each scenario to give -- it's pretty clear that

Californians have said we value addressing global warming. And I think not assigning a cost to greenhouse gases doesn't really get at the impact on -- excuse me, the question of the impact of AB-32.

Because if you're not valuing not emitting greenhouse gases in some way, then that benefit is not going to be reflected in the results.

DR. JASKE: Well, isn't it true that by presenting the carbon emissions and sort of all the direct things that are monetized as costs, that you, in effect, can do that, yourself. All you're doing by suggesting that valuing kind of metric is bringing everything together into a single monetized sort of index.

MR. WANLESS: I certainly have already looked at, made a little spreadsheet and the cost of carbon and all that sort of stuff, but I know that many people who will be looking at the IEPR, and specifically I'm sure in the Legislature, may not take the time to do that level of analysis.

And I think that that's something that would be pretty easy to do in terms of adding that cost in there. You know, you have a cost without

looking at any sort of carbon costs. And then you could present a range there to just make sure that that information's presented right up there in front, rather than making people kind of dig through and do their own stuff.

ASSOCIATE MEMBER GEESMAN: If you did that would you re-run the dispatch model?

MR. WANLESS: I think that would certainly be useful in terms of providing a better sense of the impact of carbon costs. But I think Mike said a couple times that that's not really feasible in the timeframe for the 2007 IEPR.

MR. SEZGEN: This is Osman Sezgen from PG&E. The way we use -- I mean as Dr. Jaske mentioned, looking at the carbon reductions and the overall system costs, you could look at what it's costing the system.

However, in PG&E we have a forecast of internally what carbon price would be. And when we are evaluating resources we include that price into just for that investment decision. So in that sense it would be useful to have -- last round we used the CPUC methodology, which was $8 in '04, escalating at 5 percent, for example.

But a better forecast of CO2 prices

would be useful in picking the right resources and doing cost effectiveness tests.

ASSOCIATE MEMBER GEESMAN: What do you think that price should be?

MR. SEZGEN: Oh, what do I think that price should be? I think it's something between $15 and 50. If you ask me --

ASSOCIATE MEMBER GEESMAN: Between 15 and 50?

MR. SEZGEN: Yeah.

DR. FERGUSON: Is that carbon or CO2?

MR. SEZGEN: CO2 equivalent. But it's speculative -- based on, I think, Global Energy has a logical explanation as to why it's around 50. I think they commented the same information to the CEC.

DR. FERGUSON: It's just my guess is that the system wouldn't redispatch any differently at $50 a ton of carbon dioxide. That still doesn't affect the coal, does it.

DR. JASKE: I think you're right, at around 50 it starts getting interesting, whether it would. That's my information.

DR. FERGUSON: I can answer a related question, though. And that is what wouldn't be

useful. I think this proposal to look at the impact on gas prices of these various models is a waste of time.

Several people have done it, and I just saw a report from ACEEE just came out a little while ago, doing the same -- I never place an ounce of credibility in those things. There just is so much going on in the markets, that I mean you can calculate a number, but to interpret that that if you did this it would really lower the price of gas that much I think is a crock.

I wouldn't waste your time on it, personally.

(Pause.)

DR. FERGUSON: Did you see the ACEEE report. I forget what they came up with, but you can almost do it on the back of envelope and come up with something pretty close. I'm just never impressed with --

MR. ST. MARIE: Get that on the record.

ASSOCIATE MEMBER GEESMAN: Do you think, Rich, that constrained supplies of natural gas create upward pressure on prices of natural gas?

DR. FERGUSON: Constraints like?

ASSOCIATE MEMBER GEESMAN: Less this

year than last year.

DR. FERGUSON: Not following you.

ASSOCIATE MEMBER GEESMAN: Volumetrically your amount of new natural gas supplies is less today than it was at some point in the past, does that supply impact have an upward pressure on prices?

DR. FERGUSON: Well, it's half of the upward pressure. The question is how much have existing prices, you know, lowered demand in response. So, I mean, you know how --

I think that's what's going on now. There appears to be much more gas going into storage in the last four or five months than previously. And it doesn't appear to be new production.

So the only thing I can conclude is that we're losing some more demand from the industrial sector, or it doesn't show up in the weather-related demand. But, so again, I don't know. The production has just been right around flat, and yet we're seeing more and more gas in storage. So something is going on in the demand side. But I don't know if that answers your question or not.

ASSOCIATE MEMBER GEESMAN: Well, I think

that on a multi-year basis the effort is to try and cook out some of the seasonal influence or the impact from storage.

And I think that's what motivates the ACEEE type of study. Not to give you a price projection for next year or any one particular year, but rather over a longer period of time to try and assess some impact from either increased supplies or diminished demand.

DR. FERGUSON: Well, that may be true, but my point is that California's -- I don't know what fraction of the North American market California would be, but -- 8 percent, 7 percent, something like that. So, if you're talking about the marginal change due to energy efficiency program of, I don't know, what do you think, 5 percent? You're talking about a 1 percent change in total demand in the North American market.

And there's just so much else going on that whether you could ever see that experimentally, I think, is --

But, so anyway, I mean you can do it. It doesn't hurt. I just don't think it's a very profitable exercise in terms of what useful information you get out of it.

I mean, you know, the standard economics says yes, if you back off demand then the price should go down. I mean it's standard econ-101. And I don't know what that gets you, that's all I'm saying.

ASSOCIATE MEMBER GEESMAN: Well, I think when the Commission did it in the 2003 report it ultimately got you increased attention to CPUC for the importance of utility efficiency programs for the natural gas utilities. But I take it you don't attach a value to that.

DR. FERGUSON: Correct.

ASSOCIATE MEMBER GEESMAN: Okay. Mr. Wanless, does NRDC attach a value to that increased effort on energy efficiency on the part of the natural gas utility?

MR. WANLESS: I'm sorry, can you restate your --

DR. FERGUSON: Wait, wait, wait. I wasn't saying that there's no value associated with energy efficiency. The value doesn't occur by reducing the price, that's all I was saying, but by guaranteeing to reduce the price.

DR. JASKE: Let's see, let me ask that last broad question again. Is there something in

particular that we've left out so far, or that we should redo in some fashion that would, you know, suddenly make this study significantly more valuable?

MR. SEZGEN: As you mentioned a few minutes ago, repackaging this in a way that would feed into a larger study, which would include other resources, would be very valuable.

DR. FERGUSON: I guess I'm not understanding. Are you saying that -- who's going to do this larger study that you're proposing? Is this something that you're doing, or something they should do? I'm not sure what this larger study would be.

MR. SEZGEN: Well, if the objective is to meet AB-32, and if we're comparing different options, renewables and energy efficiency obviously is the important resources there; but there are other resources which could be considered to either reduce costs or other aspects.

DR. FERGUSON: So you would like them to include these other resources?

MR. SEZGEN: No, I didn't necessarily say that. But if this is going to feed into a

study in that area, it would be useful to do that.

DR. JASKE: I detect a new participant.

MS. SMUTNY-JONES: It was just looking like too much fun. I'm Robin Smutny-Jones with the Cal-ISO. And I apologize; we are still formulating some written comments, but I felt like it was important to join the party here, both to add a couple of points and maybe ask a question.

I'm struggling with exactly what all this study is intended to be used for. But to just throw in a couple of points, I wanted to acknowledge the comments made here by SoCalEdison and others to just focus on one of the stated limitations, I think, in the study. It's well understood, and it's obviously the whole thing is a very daunting task.

But, at the end of the day we need to be able to operate the system, of course. And everybody knows that. But I think we all need to really highlight the notion that this scenario analysis work does not address operating the system.

I don't know how you change the model to get at these things. But we obviously would find that pretty important at the ISO.

And related, there are so many other efforts going on here and elsewhere in the state. Once-through-cooling proposals, you know, from the State Lands Commission; greenhouse gas obviously; RPS 33 percent proposal; and the IEPR is really the logical forum to collect all of these, which you do.

And I think we'd like to -- we will be pointing out in our written comments that we need to undertake the sort of operational focus that we have with the RPS that we've been working on with you, and together with GE and all of that's coming together, results to be coming due in July or August.

We'd probably need to drill down with all these other policies, as well, to look at the operational side. Whether it's once-through-cooling or the 33 percent. And then, to make it even more daunting, how do we knit them all together so that it actually works.

We're still kind of debating internally whether that's even possible to do. It would take a whole cadre of experts to put that together.

But just to -- we'd just like to keep all of these issues relative to operating the

system at the forefront so it doesn't get lost in the mix.

But if anybody could just -- I don't know if I just haven't read deeply enough into the studies, but just the overall purpose, what is the primary purpose of this analysis? That would be helpful to understand. Thank you.

DR. JASKE: Well, from the staff's perspective I think to answer Robin's last question first, the over-arching objective was in the context of an AB-32-type structure with at least something like proportional reductions as the starting point for what the electricity sector would be expected to do over that timeframe.

What could the various preferred resource types, if pressed, you know, beyond all the existing goals, what could they collect individually, and then collectively deliver. And at what cost and with what kind of sort of consequences that we can sort of trace through using this kind of modeling approach.

You're right that it wouldn't and doesn't yet address these detailed operational issues like the IEP project is trying to do, or that Mark is mentioning.

But it was sort of, first of all, almost -- imagine eight months ago, how would you have drawn that chart that I had in my presentation this morning about how the different scenarios would spin themselves out. That we didn't get to that implied AB-32 level was actually sort of a surprise.

And I don't at all disagree with your focus on these operational issues, but I don't exactly know how to proceed to get there. And I'm sure that that can't get there, you know, in the timeframe that we have remaining, and to provide new information to you Commissioners in this IEPR.

So, perhaps that is one of the outcomes of this project, is it leads to yet another project that is oriented to the details of how a very different system than we have today, you know, could be brought into being and what it takes to get there, and how you really have to craft that to pay attention to these operational concerns that the utilities and the ISO are raising.

MS. SMUTNY-JONES: And let me just state also that it's a constructive criticism of the study, obviously that wasn't the intent. And

additionally, the ISO is very interested in helping where we can, understanding that this probably takes quite a bit of additional time, quite a bit of additional funding, state funding.

And we would be happy to work with the CEC and whoever else is necessary to get at these operational issues at the right time.

ASSOCIATE MEMBER GEESMAN: I think you raise a good point, and we're certainly engaged together in a number of different areas. But I do think that the ISO can bring a certain operator's discipline to a lot of our analyses. And that's true not just in the short term, but over the longer term, as well.

And as we gain a better understanding of some of your operational concerns, I think it better informs the stat's planning effort, too. And that can be true in the renewable area; it can be true in the transmission expansion area; it can be true with respect to the policy emphasis that we placed on retiring and replacing existing fossil-fired boilers. And it can be true in our attempting to get a better understanding of your locational capacity requirements.

So I would strongly emphasize the need

for greater engagement between the two organizations.

PRESIDING MEMBER PFANNENSTIEL: I'd like to add onto that, and thank you, Robin, for being here, for presenting the ISO perspective.

I do think that when you named the operational issues of concern to you, you talked about 33 percent requirements, and you talked about once-through-cooling. And I think of the ones that you talked about, the once-through-cooling I hadn't heard Mike discuss in terms of the operational impacts of what that might do to our planning.

Which, getting to why are we doing this, we're doing it really for our planning. We're not doing it to specifically operate the system. You will do that. We only offer guidance in terms of the policy implications of doing so.

I don't know whether we have or intend at some point to look at the implications of once-through-cooling. But it seems to me that's in a category of power plant retirements and other very important aspects that we know are going to affect our system. And we can build them in. I don't know that this first go-round will have every one

of them into it.

You asked the fundamental question of how will this be used. And, you know, that will be, I guess, up to John and me in the IEPR in terms of how at the first level we use it. But then how is it really useful to the state, is, I think, a bigger question. And I think it will be useful to the extent it really does reflect the constraints and the concerns and the goals and the programs set forth by the state.

DR. FERGUSON: If I could ask a question of Robin and Edison. Is it your belief that in order to operate the system under these various scenarios, the costs would be a lot higher than they are now? Than they are in Mike's estimates?

I'm trying to understand, I mean of course there has to be operational and the operational issues were outside the report, but if what you're saying is that in order to make these renewable scenarios operational, the cost would be much higher than what he's estimating, then we need to know that.

I mean I don't know what you would base that on because everything I've seen is that it's pretty marginal, including what we looked at at

Tehachapi. But, what's your reaction to that?

MR. MINICK: The operational studies that I've looked at so far have looked at the variable costs of running the system basically when you have more renewables. And we've made some comments about those studies and still think there's some flaws in those studies.

They haven't looked necessarily at the fixed costs of those studies. And basically if you have to build more resources to cover contingencies, weather or drought or no wind, or whatever else affects renewable output, I don't think those have been adequately assessed.

As far as the costs, those have not been adequately assessed in the operability studies that I've seen to date. And there have been many operability studies.

As far as the total transmission costs, I think, and I haven't seen, Mike, all the data that we've given you from Edison, it could be significantly underestimated, the costs for the transmission grid to incorporate these particular resources. And by significantly I'm talking about billions, not hundreds of millions.

As you well know, we're having a whole

lot of trouble getting a transmission line that's a relatively simple transmission line, to get built to Arizona. If we're going to have to basically upgrade our system to bring in more renewables from remote sources, these are not easy transmission lines to build and integrate into our system.

The Tehachapi line, if you've seen all the details of that particular line, isn't just a line to the windmills. It's an upgrade to most of our system to incorporate that resources throughout our system.

DR. FERGUSON: But, of course, most of those upgrades were required by load growth in the area anyway. I mean that was going to be my point. I don't know the extent to which Mike tried to build in the transmission requirements related to the renewable portfolio standards, but much of the Tehachapi -- the Tehachapi costs, anyway, I mean the total 1.8 billion or whatever it was, was there for load growth and other reasons. I mean some of those lines were ancient and needed replacing anyway.

So, it would be very difficult to sort of assign, even for Tehachapi, how much of that

cost is related to Tehachapi.

MR. MINICK: I think it's easier for us to do it than maybe you anticipate.

DR. FERGUSON: Well, --

MR. MINICK: As far as load growth --

DR. FERGUSON: -- I've spent three years arguing --

MR. MINICK: -- if we build --

DR. FERGUSON: -- about it with Chacon, so --

(Parties speaking simultaneously.)

MR. MINICK: -- distributed generation we wouldn't have to do some of those upgrades. So there are benefits to all pieces of the overall planning puzzle, distributed generation, energy efficiency that reduces the load. That doesn't require us to upgrade our system, as well as bring in remote.

DR. FERGUSON: That is definitely true.

MR. MINICK: Okay. Definitely true. So we have to take a look at the entire picture. The ISO has to look at the entire picture, too.

Once-through-cooling is a huge issue. We cannot shut down 20,000 megawatts along the coast of California and still run the system.

It's technically impossible. I've been in the industry for 33 years, and that's an easy one to call.

So there are major issues, and again, Mike, I need to talk to you and see who talked to you about some of these transmission issues. Because that's the piece that I think is the most complex, as well as the operability piece.

And we've been dealing with the ISO on this 33 percent renewable analysis. Our people have been talking to the ISO. We've been doing a lot of work in the last few months. And the ISO is doing a study on their own, right now.

We really haven't got a good answer to just what it takes to build a system that we are comfortable and the ISO is comfortable, will meet our customers' needs in an operability perspective.

ASSOCIATE MEMBER GEESMAN: Well, Mark, I'd have to say that in quite a number of years of coming to these hearings I've never heard such a strong advocacy of distributed generation from your company --

(Laughter.)

ASSOCIATE MEMBER GEESMAN: -- that I

just did.

MR. MINICK: Well, sometimes we learn over time, John, okay.

ASSOCIATE MEMBER GEESMAN: Willing to accept that as a hypothesis.

(Laughter.)

ASSOCIATE MEMBER GEESMAN: We were regaled last week by the testimony of your company and the other utilities, as well, about the prospect for declining real prices in the electric sector. And one of the ways in which you got there was ignoring what we felt were a number of important capital improvement projects.

So, if, in the course of sitting down with Mike, you can identify transmission projects that he has failed to include, that would be helpful to us.

DR. JASKE: Yes, I'd be happy to talk with you further and point out those things that are buried in the bowels of the report, as well as the additional retirement work that we have underway that I mentioned earlier.

I think maybe we've come to sort of a stopping point. I see that there actually are a number of folks in the room who perhaps missed

their opportunity to say something and --

PRESIDING MEMBER PFANNENSTIEL: Well, let's see. This is the opportunity. If anybody here would like to offer comments, suggestions, criticism, next steps -- well, we'll talk about next steps in a minute -- but any comments on this work that's been done. Mike has indicated that there's a lot of work in progress, and we have some opportunities. And we would really appreciate hearing from you.

Is there anybody on the phone? No. Okay.

Mike, why don't you talk about next steps.

DR. JASKE: Okay, they actually are very straightforward. We are, as I said before, maybe no more than a week or two weeks away from producing an analysis of the retirement and replacement of aging power plants in actually the Southern California Edison service area.

We've already told Edison transmission people that we will be giving them a preview of that study, because we want their feedback. And I will be sure to include Mark in that distribution.

Presumably then by around the end of

this month we'll try to put something forward that they may or may not agree with -- oh, and the ISO is also included in that review. The ISO has given us some modest feedback so far.

So we'll have something to talk about on August 16th at that workshop, whether we argue about it or, you know, fuss about little details, remains to be seen.

It is an important aspect of this project that we want to try to get right because we are grappling with how to do at least a simplified version of resource adequacy extended out, you know, multiple years into the future in the context of retirements, in the context of several different alternative sort of scenarios emphasizing efficiency or renewables, or both.

And, you know, it raises many of the issues that Mark has mentioned. It may well just be the first of several steps that are needed to go down this path.

I think that's the principal next step that the staff has underway. To the extent that the Committee wants to give us some direction of some repackaging or some, hesitate to say, minor analysis, but it's only minor in the timeframe

that we have to provide some results useful to you in preparing the policy report, we're happy to be in dialogue with you about that.

And then, of course, to the extent that the IEPR wants to sort of give direction both to staff or maybe to a group of parties about things that we can work on for the next cycle, that's also something that we can hear from you either informally or if you want to memorialize it in the IEPR, itself. That's one way to raise it in higher visibility.

ASSOCIATE MEMBER GEESMAN: I guess there's one area that we addressed at the last workshop, and based on Mr. Wanless' comments, I want to make certain that we address again at this one. And that is constraints created by SB-1368.

And as I characterized it at the last workshop, parallel requirements adopted by the State of Washington. I remain concerned about the buildup in reserve margins, which I know you're going to address in your next go-round.

And I think my question is specifically if you expect new coal plants to be built during your period of analysis despite SB-1368 and the State of Washington limitation, I think you need

to directly identify that. And provide some plausible explanation as to why you think that is likely to occur.

I agree with the notion that SB-1368 and the State of Washington limitation do not really represent a constraint to short-term imports from existing coal plants. But I do think that as it regards investment in new projects, that such a substantial portion of western load, that I think it may be quite difficult to envision new plants coming online.

If you analysis shows differently, I think you need to be prepared to specifically identify that and justify it.

DR. JASKE: Yes, I do have in mind that issue. And we will perhaps prepare some supplemental documentation that makes clear what new coal plant additions that we have, where they're located and sort of what market we expect them to be serving.

PRESIDING MEMBER PFANNENSTIEL: Further discussion?

Mike, you and your team have made an incredible contribution to both the intellectual effort that's going into the IEPR, and I think to

our way of structuring how we think about bringing those pieces together.

So, thank you and keep going. We're not done yet.

If there's nothing else, Lorraine, do you have any final?

MS. WHITE: No, ma'am.

PRESIDING MEMBER PFANNENSTIEL: Okay, we'll be adjourned.

(Whereupon, at 11:39 a.m., the Committee workshop was adjourned.)

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CERTIFICATE OF REPORTER

I, PETER PETTY, an Electronic Reporter, do hereby certify that I am a disinterested person herein; that I recorded the foregoing California Energy Commission Committee Workshop; that it was thereafter transcribed into typewriting.

I further certify that I am not of counsel or attorney for any of the parties to said workshop, nor in any way interested in outcome of said workshop.

IN WITNESS WHEREOF, I have hereunto set my hand this 3rd day of August, 2007.